

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2020-263-E — ORDER NO. 2021-[____]

[DATE]

Cherokee County Cogeneration Partners,)
LLC)

Complainant/Petitioner,)

v.)

Duke Energy Progress, LLC and)
Duke Energy Carolinas, LLC,)

Defendants/Respondents.)

**PROPOSED ORDER OF
DUKE ENERGY CAROLINAS,
LLC AND DUKE ENERGY
PROGRESS, LLC**

INTRODUCTION

This matter comes before the Public Service Commission of South Carolina (the Commission) on the Complaint filed by Cherokee County Cogeneration Partners, LLC (Cherokee) against Duke Energy Carolinas, LLC (“DEC”) and Duke Energy Progress, LLC (“DEP” and together with DEC, the “Companies”). Cherokee’s Complaint alleges that the Companies have not acted in good faith in response to Cherokee’s efforts to negotiate the terms of a power purchase agreement (“PPA”) pursuant to their obligations under Section 210 of the Public Utilities Regulatory Policies Act of 1978, 16 U.S.C. § 824a-3 (“PURPA”), as implemented by this Commission. Specifically, Cherokee alleges that DEC and then DEP have refused to accept Cherokee’s initial offers to sell power to each utility as legally enforceable obligations, refused to provide supporting information regarding the avoided cost pricing offered, and has treated Cherokee in a discriminatory manner by offering avoided cost rates and terms and conditions that

Cherokee alleges were less favorable than the rates being offered to other QFs at the time Cherokee offered to sell its power to DEC in September 2018.

A hearing was held on July 26 and 29-30, 2021. Cherokee, represented by John J. Pringle, Jr., Esquire, Jenna L. McGrath, Esq., and William DeGrandis, Esq. presented the testimony of Nathan Hanson, Senior Vice President, Energy and Commercial Management of LS Power and Senior Vice President of Cherokee, and Kurt Strunk, an expert witness employed by National Economic Research Associates, Inc. The Companies, represented by Frank R. Ellerbe, III, Esq., E. Brett Breitschwerdt, Esq., and Tracy S. DeMarco, Esq., presented the testimony of Michael Keen, John Freund, Glen A. Snider, and Kendal C. Bowman all of the Companies. The Office of Regulatory Staff (“ORS”), represented by Jenny R. Pittman, Esq. and Jeffrey M. Nelson, Esq., presented the testimony of Dawn M. Hipp, Chief Operating Officer of ORS.

BACKGROUND

The testimony of Cherokee Witness Strunk and DEC/DEP Witnesses Bowman and Snider reviewed the history of PURPA and its avoided cost rates framework. Witness Strunk and Witness Bowman generally presented consistent testimony on the history and purpose of PURPA, with Mr. Strunk testifying as an economist familiar with PURPA and Ms. Bowman testifying as an attorney and regulatory expert that had previously testified before both the Federal Energy Regulatory Commission (“FERC”) and the North Carolina Utilities Commission (“NCUC”) on PURPA policy and implementation. According to DEC/DEP Witness Bowman, Title II of PURPA, specifically Section 210, established in 1978 a new policy of encouraging development of non-utility owned cogeneration and small power production facilities, largely driven by concerns that traditional electric utilities during the 1970s were reluctant to purchase power from and to sell power to these nontraditional facilities. (Tr. Vol. 3, p. 502.5.) To encourage development of these new wholesale

power generators, Congress mandated that they should have the right to sell power to and purchase back-up power from traditional utilities, and also should be exempt from certain financial and rate regulation burdens imposed on traditional public utilities, effectively exempting these generators from federal or state regulatory oversight of their books and cost of service. (*Id.*) However, Section 210 was also expressly focused on controlling costs for consumers, requiring utilities to purchase power from cogenerators and small power production facilities at non-discriminatory rates that are just and reasonable to the utility's customers and in the public interest. (Tr. Vol. 3, p. 502.6.) Cherokee Witness Strunk, DEC/DEP Witness Bowman, and ORS Witness Hipp agreed that PURPA and FERC's implementing regulations effectively prohibit a utility and its customer from being required to pay a rate to a QF that would exceed the incremental cost of its alternative options of generating or purchasing electric energy or "avoided cost", *i.e.*, the cost to the utility which "but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." 16 U.S.C. § 824a-3(b), (d). The parties and ORS agree that it is the purchasing utility's incremental or "avoided" cost that PURPA requires to be paid, which ensures customers remain "indifferent" between the costs of utility or non-utility generation. (Tr. Vol. 3, pp. 502.5-.7; Tr. Vol. 1, pp. 126.6-.8; Tr. Vol. 3, pp. 568.2-.3.) DEC/DEP Witness Bowman emphasized that Congress was clear that PURPA was not intended to require the utility and ratepayers of a utility to subsidize QFs. (Tr. Vol. 2, p. 502.7.)

The parties also recognize that PURPA delegates to this Commission and other state commissions the responsibility of implementing PURPA's "mandatory purchase" requirements, consistent with the regulations established by FERC. Notably, the Energy Freedom Act of 2019 ("Act 62"), enacted S.C. Code Ann. § 58-41-20, now prescribes South Carolina's implementation of PURPA and established a number of new requirements for enhanced Commission oversight of

PURPA implementation. Witness Bowman explained that Act 62 now requires the Commission to review and approve DEC's and DEP's avoided cost rates and methodology used to calculate those rates every two years, and S.C. Code Ann. § 58-41-20(A) specifically provides that "any decisions by the Commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the [FERC]'s implementing regulations and orders, and nondiscriminatory to small power producers," and directs that the Commission, in implementing Act 62, "shall strive to reduce the risk placed on the using and consuming public." S.C. Code Ann. § 58-41-20(A). (Tr. Vol. 3, pp. 502.11-.12; Tr. Vol. 1, pp. 126.6-.7.) Accordingly, to comply with PURPA and South Carolina law, the Commission must ensure that the rates for purchase from QFs remain just and reasonable to the utility and do not exceed the utility's avoided cost. (Tr. Vol. 3, pp. 502.7-.8.)

DEC/DEP Witness Bowman also highlighted that on July 16, 2020, FERC issued Order No. 872. *Qualifying Facility Rates and Requirements, Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041 (Jul. 16, 2020) ("Order No. 872"), *affirmed and clarified by* Order No. 872-A, 173 FERC ¶ 61,158 (Nov. 19, 2020); Order No. 872 at P 9. Among other changes, Order No. 872 provided state commissions increased flexibility in establishing avoided cost rates for purchases of QF power. Witness Bowman explained that FERC reemphasized in Order No. 872 that PURPA was not a directive to encourage QF development without limitation, and that in addition to providing for the encouragement of cogeneration and small power production, the law also provided that FERC could not prescribe a rule that provided for a rate that exceeds avoided cost, and was not intended to subsidize QFs. (Tr. Vol. 3, pp. 502.8-.10; Order No. 872 at PP 9-12, 351.)

Witness Bowman explained that PURPA's requirements apply to all QFs, which comprise two classes of generators: (1) cogeneration facilities meeting certain operational and efficiency requirements established by FERC's regulations and (2) facilities defined as "small power producers." Act 62 was specific to small power producers, as that term is defined in federal law, S.C. Code Ann. §§ 58-41-10(14), 58-41-20(A), which generally include QFs with a generating capacity equal to or less than 80 MW. (Tr. Vol. 3, pp. 502.12-.13.)

DEC/DEP Witness Bowman also noted that, consistent with FERC's regulations, the Commission has approved DEC's and DEP's "standard offer" tariffs for small QFs, as required by FERC's implementing regulations. Since 2016, standard rates and terms for purchases from QFs have been available to QFs that are 2 MW and smaller. Order No. 2016-349, Docket No. 1995-1192-E (May 12, 2016). Consistent with this historic treatment, Act 62 mandates the standard offer applies to QFs that are 2 MW or smaller. S.C. Code Ann. § 58-41-10(15).

As described by Cherokee Witness Hanson and agreed to by DEC/DEP Witnesses Bowman and Keen, Cherokee is a large 98 MW cogeneration QF located in DEC's service territory. Witness Bowman noted Cherokee's size actually exceeds the 80 MW size limit for small power producer QFs. (Tr. Vol. 1, p. 15.3; Tr. Vol. 2, p. 242.5; Tr. Vol. 3, p. 502.13.)

Due to its 98 MW size, DEC/DEP Witness Snider noted that Cherokee significantly exceeds eligibility for standard offer avoided cost rates, (Tr. Vol. 2, p. 390.30), and Cherokee Witness Strunk agreed that Cherokee has never been eligible for DEC's or DEP's standard offer tariff. (Tr. Vol. 1, p. 172; Tr. Vol. 3, p. 600.) For large QFs not eligible for the standard offer, FERC's regulations permit utilities and QFs to negotiate mutually-agreeable, nondiscriminatory terms and conditions that differ from avoided cost rates calculated pursuant to the standard offer. 18 C.F.R. § 292.301(b). Witness Bowman also highlighted that the Commission has directed

electric utilities and larger QFs to undertake good faith negotiations of purchase agreements in its early PURPA orders since the 1980s, pointing to Order No. 81-214 at p. 9, Docket No. 80-251-E (Mar. 20, 1981) (recognizing “the substantial flexibility of negotiation which is reserved to each contracting party under part 292.301(b)”) and Order No. 85-347 at pp. 20-21, Docket No. 80-251-E (Aug. 2, 1985) (“The Commission urges voluntary negotiations of long-term contracts”). In its Order No. 2016-349 approving standard offer tariffs for DEC and DEP, the Commission also directed that all rates for QFs larger than two MW, or that are otherwise ineligible for the standard tariffs, be negotiated under PURPA and FERC’s implementing regulations. (Tr. Vol. 3, pp. 502.13-.16.)

Witness Bowman and ORS Witness Hipp also focused on the impact of QF purchased power transactions on DEC’s and DEP’s customers. They emphasized that the Companies’ customers pay for all purchases of QF power, the costs of which are a wholesale purchased power expense that is passed through to customers through DEC’s and DEP’s fuel clause proceedings. (Tr. Vol. 3, pp. 502.11, 568.2-.3.)

LEGALLY ENFORCEABLE OBLIGATION

Cherokee Witness Hanson testified that Cherokee established a legally enforceable obligation or “LEO” with DEC and later with DEP in the fall of 2018 by offering to sell its power, as Cherokee has a right to do under PURPA. (Tr. Vol. 1, p. 15.9.) Specifically, he claimed that Cherokee established a LEO with DEC by submitting a September 17, 2018 letter, its FERC Form 556 and a form entitled “Notice of Commitment to Sell the Output of a Qualifying Facility” (“Notice of Commitment Form”) to DEC. Through the letter, Cherokee “made a ‘legally binding offer of all capacity and energy associated with the Cherokee Facility, meaning that Cherokee would sell all the output of the Cherokee Facility to DEC.” (Tr. Vol. 1, p. 15.12.,; Hrg. Ex. 1.)

Witness Hanson also claimed that that Cherokee's subsequent actions on December 12, 2018, of delivering the Notice of Commitment Form and accompanying cover letter to DEP constituted establishment of a LEO with DEP as of that date. (Tr. Vol. 1, pp. 15.15-.16.; Hrg. Ex. 1.) He asserted that submitting a Notice of Commitment Form to DEP did not undercut Cherokee's commitment to DEC, "given Duke's unique joint dispatch arrangement and the common employees between the companies," it was "perfectly reasonable" for Cherokee to offer to sell power to both companies. (Tr. Vol. 1, p. 15.16.) He also contended that the Companies' disagreement that these communications constituted LEOs puts form over substance. (Tr. Vol. 1, pp. 15.18-.19.) Witness Hanson argued that DEC created barriers to Cherokee executing a PPA, by refusing to acknowledge a LEO, providing different rates and a proposed 5-year PPA term in 2018 than was available to other QFs under the standard offer at the time, offering a "must-take" form of PPA that was not the same as the existing 2012 PPA, and imposing an "arbitrary deadline" before the avoided cost rate proposal DEC provided to Cherokee expired. (Tr. Vol. 1, p. 15.23; Tr. Vol. 3, pp. 660.2, .16.)

In response, DEC/DEP's witnesses described the concept of a legally enforceable obligation under PURPA, along with the DEC's and DEP's standardized process for providing avoided cost rates and PPAs to large QFs, and explained that Cherokee's communications and non-binding offer to sell power in fall 2018 did not establish a LEO to sell power under PURPA because Cherokee did not actually make a legally enforceable commitment to sell its power at DEC's or later DEP's avoided cost rates.

Witness Bowman discussed that FERC's regulations implementing PURPA provide QFs the option to sell energy to the utility on an "as available" basis or to sell capacity and energy pursuant to a legally enforceable obligation at a forecasted avoided cost rate. 18 C.F.R. §

292.304(d). If a QF seeks to exercise its rights to sell power and is prepared to legally obligate itself to deliver its capacity and energy to the utility over future delivery term, PURPA provides the QF the option to contract to receive the utility's avoided cost, calculated either at the time power is delivered or prior to commencement of the term "at the time the obligation is incurred."

Id. Witness Bowman testified that the LEO concept created by FERC in its PURPA regulations is designed to protect the QF's right to sell power to the utility, as the QF and the utility can either negotiate and agree to a PPA or, where the utility refuses to enter into a contract, the QF can bind the utility to purchase power from the QF by establishing a non-contractual, but still binding, LEO. She noted FERC's explanation that a QF's right to sell pursuant to a LEO was intended "to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility *merely by refusing to enter into a contract with the qualifying facility.*" Order No. 69, 45 Fed. Reg. at 12,224 (emphasis added). FERC has also made clear that "the establishment of a legally enforceable obligation turns on the QF's commitment, and *not* the utility's actions." *FLS Energy, Inc.*, 157 FERC ¶ 61,211 at P 24 (Dec. 15, 2016) (emphasis in original). (Tr. Vol. 3, pp. 502.19-.20.)

Witness Bowman noted that FERC's updated regulations approved in Order No. 872 now require QFs to demonstrate commercial viability and financial commitment to obtain a LEO. She explained that these requirements are intended to help ensure that the QF is making a real and binding commitment at the time it asserts a LEO and proceeds with a contract to sell power in order to ensure that the electric utility obligated to purchase the QF's power can actually rely upon the QF's capacity for the future term of the QF's obligation. (Tr. Vol. 3, pp. 502.20-.21.)

Witness Snider also emphasized the purpose of the LEO is to memorialize the QF's commitment to sell power to the utility at the utility's avoided costs, so that the utility can then

rely on the QF's capacity and energy to serve its customers. She also explained that from a resource planning perspective, the utility cannot rely upon the QF to deliver capacity and energy over a future term to serve customers unless and until the QF signs a new PPA committing itself to do so. (Tr. Vol. 2, pp. 390.8-.10.)

Witness Snider discussed the process DEC and DEP follow for small standard offer QFs and larger QFs to establish a LEO committing to sell power to DEC or DEP in South Carolina. Under Act 62, small power producers may establish a LEO by submitting to the utility the Notice of Commitment Form first approved by the Commission in Order No. 2019-881(A). (Tr. Vol. 2, p. 390.11.) He explained that, for QFs larger than 2 MW not eligible for the Commission-approved standard rates and terms, such as Cherokee, the Companies follow a standardized process for negotiating a PPA with a QF. (*Id.*) That process begins with a QF offering to sell its capacity and energy over a future contract term and a request for avoided cost pricing and a PPA. (*Id.*) DEC or DEP then develops and provides the large QF its avoided costs based upon inputs and assumptions as of the time the QF makes its offer to sell power and an executable form PPA for the large QF. (Tr. Vol. 2, p. 390.12.) The avoided cost pricing that is tendered to the QF remains valid for a reasonable period of time to allow the QF and the utility to work to finalize the PPA (normally 60 days). If the QF elects not to proceed with finalizing the PPA for execution, the QF may request new pricing in the future. If agreement cannot be reached on specific terms of the PPA, the QF or the utility may petition the Commission for review to resolve any disputes. Once the parties are in full agreement on all terms and conditions of the PPA, the utility would prepare and forward to the QF owner a final, executable PPA, which is executed by the QF and returned to DEC or DEP. (Tr. Vol. 2, pp. 390.11-.13.)

The Companies' witnesses disagreed that Cherokee actions demonstrated a legally enforceable and binding commitment to sell power to DEC or DEP as Cherokee claims. Witness Snider stated that the Notice of Commitment form Cherokee used in its September 17, 2018 communication to DEC was applicable only to small standard offer QFs of 2 MW or less. (Tr. Vol. 2, p. 390.14.) Witness Snider also emphasized that even the small QF Notice of Commitment Form that Cherokee modified and submitted to DEC does not do what Cherokee suggests, as it does not create an indefinite commitment locking in avoided cost rates without the QF actually proceeding to execute a PPA and contractually bind itself to sell its power over a future delivery term. Witness Snider explained that Section 6 of the Notice of Commitment Form that Cherokee submitted provides only a limited 30-day period from the date that DEC provides an executable PPA for the QF to sign a PPA at the provided avoided cost rate or the notice of commitment terminates. He clarified that a non-contractual LEO is not open-ended into perpetuity, which would be detrimental to customers. (Tr. Vol. 2, pp. 390.14, 481-82.)

DEC/DEP Witnesses Snider and Witness Bowman also explained how Cherokee's actions during the 2018-2020 timeframe made clear that it did not actually commit its output to either DEC or DEP. First, six days after mailing its letter to DEC, Cherokee offered to sell all of its output to DEP pursuant to DEP's non-PURPA 2018 capacity solicitation. Then Cherokee sent essentially the same letter to DEP asserting a LEO to sell all its capacity and energy from the QF facility to DEP in December 2018. Second, Cherokee continually rejected the Companies' avoided cost offers and, instead, counter-offered to sell at prices above avoided cost rates, which was inconsistent with PURPA and FERC's regulations limiting utility purchase obligations to rates set based on the utility's avoided cost. (Tr. Vol. 2, pp. 390.14-.16; Tr. Vol. 3, p. 502.23.) Witness Bowman also noted Cherokee's recent statements to FERC that upon expiration of the 2012 PPA,

it had the right to and was contemplating selling its output to third parties. (Tr. Vol. 3, p. 502.24.)

Witness Snider also noted that Cherokee's actions were inconsistent with FERC's recent statements in Order No. 872 regarding the importance of QFs memorializing a commitment to sell to a utility so that the utility can rely on the QF's energy and capacity to reliably plan its system and serve its customers, as DEC cannot rely on Cherokee's energy and capacity to reliably plan and serve. (Tr. Vol. 2, p. 390.16.)

Witness Bowman also testified that Cherokee's generalized suggestion that it can sell its power under a PURPA PPA to both DEC and DEP is unprecedented and incorrect. She stated that DEC and DEP are each separate "electric utilities" under PURPA. As such, they are independently obligated to implement PURPA and purchase QF power at each utility's respective avoided costs. She explained that the Companies' Joint Dispatch Agreement ("JDA") enables DEC and DEP to transfer economic energy between DEC's and DEP's generating fleets from the system with lower marginal energy costs to displace higher cost system generation on the other system, but does not enable DEC and DEP to operate as a single utility nor does it in any way facilitate joint capacity planning by DEC and DEP. The JDA does not change that independent PURPA obligation or in any way "merge" the two Companies into a single utility. (Tr. Vol. 3, pp. 502.16-.19.)

DEC/DEP Witness Keen testified in response to Cherokee's claim that the Companies created barriers to execution of a PPA that this was not true as both Companies treated Cherokee like all other large QFs and actively sought to execute a successor PPA with Cherokee.

Witness Keen provided a detailed narrative and timeline of communications between the parties demonstrating that throughout the two-year plus discussion, the Companies at all times responded promptly to Cherokee's requests for avoided cost rates, calculated those rates as of the dates Cherokee requested even while disputing the establishment of a LEO, and appropriately

responded to Cherokee's requests for information regarding the Companies' avoided cost methodology. That timeline shows that on September 17, 2018, Cherokee sent a letter to DEC attaching its FERC Form 556 and a modified version of the Notice of Commitment Form then used for small QFs less than 5 MW in North Carolina, stating that it was "making a legally binding offer of all capacity and energy associated with the Facility *to DEC* as of January 1, 2021" under PURPA. (Hrg. Ex. 13, at 12 (Timeline Attachment 2) (emphasis added).). DEC responded by letter on October 5, 2018, stating that Cherokee's written notice of its intent to sell power for a new contract term did not establish a mutually-binding legally enforceable obligation, but that DEC, as required by PURPA, would "commence negotiations with Cherokee" and "deliver its avoided costs as well as a form PPA that DEC would agree to execute in order to establish a legally binding arrangement to purchase Cherokee's full output of energy and capacity over a five-year term commencing on January 1, 2021." (Hrg. Ex. 13, at 17 (Timeline Attachment 3).)

On October 31, 2018, DEC provided its avoided cost rates "calculated using DEC's standard system [peaker] methodology for [QFs] based on DEC's September 2018 system costs" and standardized form of PPA that DEC would execute if Cherokee committed to proceed with the transaction. (Hrg. Ex. 13, at 21 (Timeline Attachment 4).) After limited communications between DEC and LS Power representatives, including Cherokee presenting an unsolicited term sheet, on December 12, 2018, Cherokee sent similar communications purporting to "mak[e] a legally binding offer of all capacity and energy associated with the Facility *to DEP* as of January 1, 2021" under PURPA. (Hrg. Ex. 13, at 27 (Timeline Attachment 6) (emphasis added).)

On December 21, 2018, DEP provided Cherokee a written response committing to commence negotiation and to provide its avoided cost rates and a form PPA. (Hrg. Ex. 13, at 36 (Timeline Attachment 7).) On that same day, Witness Keen also timely provided an emailed

response to Cherokee's term sheet and limited efforts to commence negotiation with DEC, explaining that the offered rates exceed DEC's avoided costs and that Cherokee's recent communications to DEP effectively superseded its prior notice of intent to sell to DEC. (Hrg. Ex. 13, at 39 (Timeline Attachment 8).) As Witness Keen noted, Cherokee either rejected or let expire without accepting both DEC's and later DEP's avoided cost rates. (Tr. Vol. 2, pp. 242.10-15.)

Witness Keen also testified that in June 2020, at Cherokee's request, DEP provided Cherokee with updated avoided cost rates together with a Commission approved large QF form PPA for a five-year term, which offer Cherokee also allowed to expire. (Tr. Vol. 2, p. 242.19.) In September 2020, following discussions between the parties DEC offered Cherokee a dispatchable tolling agreement structure, similar to the 2012 PPA, with a 10-year term. (*Id.*) Witness Keen explained that while Cherokee does not qualify under Act 62 for a ten-year contract because it is not a small power producer QF, and the Companies' practice has been to offer five-year terms to such facilities, in an effort to create a contractual structure that was agreeable to Cherokee, DEC opted to extend the contract term and offered avoided cost rates to ten years. (*Id.*)

Witness Keen also explained that the Companies originally offered Cherokee a must-take, non-dispatchable PPA as that is the standard Commission-approved structured offered to large QFs. (Tr. Vol. 2, p. 242.20.) He also noted that this must-take structure of PPA was consistent with the 1994 PPA between DEC and Cherokee that was the predecessor to the 2012 PPA. (*Id.*) Witness Keen explained that because PURPA and Act 62 allow flexibility in contracting between utilities and large QFs, DEC offered Cherokee a dispatchable tolling agreement in September 2020 in a good faith attempt to reach a resolution between the parties and execute a new PPA before the 2012 PPA's December 31, 2020 termination date. (*Id.*) He also noted that Cherokee rejected the September 2020 offer as well as a 10-year dispatchable tolling PPA structure with avoided cost

rates calculated as of October 2020 that DEC offered in advance of the February 2021 mediation. (*Id.*) He noted that the February 2021 rates generally aligned with the timing of Cherokee's complaint and represent the most current rates available prior to the end of the 2012 PPA's term. (Tr. Vol. 2, pp. 242.19-.20.)

Witness Keen contrasted the Companies' actions following their standardized process for negotiating with large QFs with Cherokee's actions, which included stalling the negotiations at several junctures by rejecting or letting expire five different avoided cost rate offers, never engaging in active negotiations of the PPA form, and submitting counter-offers containing rates much higher than either DEC or DEP's actual avoided costs. (Tr. Vol. 2, pp. 242.21-22.)

Witness Keen also testified that the Companies responded in a timely manner to Cherokee's intermittent requests for further discussions and information regarding the methodology and inputs used to calculate the Companies' avoided cost rates and provided a timeline of communications between the Companies and Cherokee. (Tr. Vol. 2, p. 242.17; Hrg. Ex. 12.) He noted that it was not until April 30, 2019—months after both the DEC and DEP rates had expired—that Cherokee requested information on the methodology that the Companies used to calculate DEC's and DEP's avoided cost rates, to which the Companies responded in June 2019. The Companies had no further communications from Cherokee until March 2020. (Tr. Vol. 2, pp. 242.18-.19, 288-89.)

Witness Keen also explained that the Companies' responses to Cherokee's requests for information were consistent with the Companies' responses to similar requests for information supporting avoided cost rate calculations, and that the Companies provided additional information beyond their usual responses at a meeting between the parties in February 2021. (Tr. Vol. 2, p. 338.17-.19; Hrg. Ex. 12.) Importantly, Cherokee never told the Companies that the supporting

information they provided was insufficient. (Tr. Vol. 2, pp. 332-33 (“[W]e got [Cherokee’s] request [for information] in May of that year, and we responded in June. And then I didn’t hear from them for almost ten months after that. . . . During that next nine, ten months . . . , there was no additional conversation at all and definitely nothing on requesting additional information.”).)

LENGTH AND STRUCTURE OF POWER PURCHASE CONTRACT

Cherokee takes issue with the term of contract and must-take PPA structure that the Companies initially offered before transitioning to offer Cherokee a 10-year dispatchable tolling structure in fall 2020. Witness Hanson noted the dispatchable tolling structure of the current extended PPA and pointed to the Companies’ offering a fiveyear term, which is shorter than “Cherokee’s previous contracts.” (Tr. Vol. 1, p. 15.19.) Both Witnesses Hanson and Strunk recommend that the Commission adopt a ten-year dispatchable tolling agreement structure. (Tr. Vol. 3, pp. 660.17, 598.16.)

DEC/DEP Witness Keen explained that DEC first contracted to purchase from the Cherokee Facility in 1994 under a 15-year non-dispatchable must-take PPA. (Tr. Vol. 2, pp. 242.7.) He noted that the successor, dispatchable tolling PPA between DEC and Cherokee was executed in June 2012 for a 7.5-year term set to terminate December 31, 2020. (*Id.*) Witness Keen and Witness Freund testified to the distinction between a non-dispatchable must-take PPA structure and a dispatchable tolling PPA structure, which is primarily that under a dispatchable tolling arrangement DEC purchases the fuel to run the facility and decides when to dispatch the facility. (Tr. Vol. 2, pp. 242.7-.8, 338.8.)

DEC/DEP Witness Freund explained that the calculation of rates for a dispatchable tolling PPA differ from a non-dispatchable must-take PPA only in that the inputs to the dispatchable tolling rates reflect the specific characteristics of the facility itself rather than a generic QF profile;

otherwise, the methodology for calculating the rates remains the same. (Tr. Vol. 2, pp. 338.8-.9, 242.7-.8.) Witness Keen noted that most PURPA PPAs in the Carolinas are structured as must-take agreements, including the 1994 Cherokee-DEC PPA. (Tr. Vol. 2, p. 242.8.) He also noted that this is also the standard form of PPA approved in Order No. 2019-881(A) for use in PURPA transactions with QFs larger than 2 MW and that the Companies' current large QF PPA is a must-take agreement. (*Id.*)

The Companies' witnesses testified that the rates DEC and DEP provided to Cherokee in October 2018, February 2019, and June 2020 reflected a non-dispatchable must-take PPA levelized over a five-year term, and that the rates provided in September 2020 and February 2021 reflected a non-dispatchable tolling PPA levelized over a 10-year term. (Tr. Vol. 2, pp. 242.12, 338.7-.9.) With regard to the contract term, Witness Keen explained that, since Cherokee does not qualify as a small power producer under Act 62, the ten-year contract length mandated in Act 62 is not applicable to Cherokee. (Tr. Vol. 2, p. 242.9.) He noted that the Companies' historical practice has been to offer a five-year term for solar QFs and other all large small power producer QFs prior to Act 62's enactment and also for cogeneration QFs like Cherokee that do not qualify for a 10-year term under Act 62. However, in an effort to create a contractual structure agreeable to Cherokee, DEC opted to extend the previous five-year term to a 10-year term for the September 2020 and February 2021 offers. (*Id.*)

Regarding the PPA structure, Witness Keen explained that the Companies originally offered Cherokee a must-take, non-dispatchable PPA as that aligned with the PPA structure offered to other large QFs and also with the current Commission-approved large QF PPA. He noted that the must-take structure is also consistent with the 1994 PPA between DEC and Cherokee that was the predecessor to the 2012 PPA. (Tr. Vol. 2, p. 242.20.) At the hearing, Witness Keen disagreed

that the must-take PPAs offered to Cherokee were specific to solar QFs, and clarified that the PPA offered to Cherokee in late 2018 was the same template that would have been offered to any other type of QF in fall 2018 regardless of the technology. (Tr. Vol. 2, pp. 331-32.)

In summary, witness Keen explained that because PURPA and Act 62 allow flexibility in contracting between utilities and large QFs, DEC offered Cherokee a 10-year dispatchable tolling agreement in September 2020 in a good faith attempt to reach a resolution between the parties and execute a new PPA before the 2012 PPA's December 31, 2020 termination date. (Tr. Vol. 2, p. 242.20)

ALLEGED DISCRIMINATORY TREATMENT

Cherokee's witnesses claim that DEC discriminated against Cherokee by not providing avoided capacity payments, pointing to DEC's standard offer rate available to QFs under Schedule PP, which Witness Strunk acknowledged was available only to QFs 2 MW or less and not available to large QFs like Cherokee. (Tr. Vol. 1, pp. 15.14, .21, 126.10, .12-13.) At the hearing, Witness Strunk admitted that he had no evidence and was not aware of DEC or DEP providing more favorable avoided cost rates to other large QFs than those offered to Cherokee, and did not have a basis to dispute Duke's testimony that the Companies treat all large QFs the same. (Tr. Vol. 1, 182-83, 186.) Witness Hanson admitted that Cherokee did not raise the alleged discriminatory treatment with ORS or engage ORS regarding its negotiations with DEC or DEP prior to filing the complaint to attempt to resolve the dispute, nor did Cherokee intervene in the Companies' avoided cost cases that were filed November 30, 2018, and then refiled after the passage of Act 62 and pending through late 2019. (Tr. Vol. 1, pp. 70-72.)

Witness Snider pointed out that the Schedule PP available in September 2018 was available only to QFs eligible for the standard rate schedule, which is QFs 2 MW or less, which does not

include the Cherokee Facility. He explained that DEC applied the same process and methodology that it uses for all large QFs to calculate the rates for Cherokee. (Tr. Vol. 2, p. 390.30.) At the hearing, Mr. Snider testified that DEC and DEP were not discriminatory in developing the avoided capacity and avoided energy rates provide to Cherokee and treated Cherokee like all other large QFs in late 2018 when the Companies offered must-take agreements with five year terms to all large QFs. (Tr. Vol. 2, pp. 263-64.) Finally, Witness Freund testified that the Companies treated Cherokee like all other large QFs by levelizing avoided capacity costs based on the first year of capacity need over the term of the contract. (Tr. Vol. 2, p. 371.)

METHODOLOGY TO CALCULATE AVOIDED COST RATES

Cherokee claims that it was inappropriate for DEC's avoided cost pricing offered to Cherokee in 2018 to not include payment for capacity because DEC's Schedule PP approved by Order No. 2016-349 still included avoided capacity value. (Tr. Vol. 1, pp. 15.13, 26.5-.6.)

Cherokee Witness Strunk presented alternative avoided cost rates for Cherokee that adopted DEC's September 2018 avoided energy pricing and recalculated the avoided capacity rates based upon prior standard offer Schedule PP capacity rates approved by Order No. 2016-349 and in effect since May 2016. (Tr. Vol. 1, p. 26.12.) Witness Strunk then converted the fixed dollars per MWh energy pricing included in the rates DEC provided in October 2018 and his alternative avoided capacity rates to a \$/kW-year payment structure comparable to the 2012 dispatchable tolling PPA. His calculation resulted in a \$63/kW-year avoided energy rate and a \$47/kW-year avoided capacity rate, for a total avoided cost rate of \$110/kW-year. (Tr. Vol. 1, pp. 26.15-.16; Hrg. Ex. 2.)

At the hearing, Witness Strunk testified in response to Chairman Williams that his dispatchable tolling rate structure translated into a \$47/MWh must-take PPA price. He agreed that

his proposed rate was at least 24% (by his calculation) below the rates under the current extended PPA, accepting that the rates under the current 2012 PPA are too high and need to be “reset.” (Tr. Vol. 3, p. 629.13-.23)

DEC/DEP Witness Snider presented a detailed overview of the standardized application of the peaker methodology that DEC and DEP use to calculate avoided cost rates. Witness Snider testified that the Commission has consistently accepted the Companies’ use of the peaker methodology to quantify DEC’s and DEP’s forecasted avoided capacity and energy costs, and specifically determined in Order No. 2019-881(A) that the peaker methodology is “a reasonable and appropriate methodology to fully and accurately quantify DEC’s and DEP’s forecasted capacity and energy cost to be avoided by purchases from QFs.” (Tr. Vol. 2, p. 390.17.) He explained that the Companies’ established practice is to utilize the same peaker methodology to determine avoided cost rates for Standard Offer as well as large QFs. He noted that pursuant to Order No. 2020-315(A), the Companies update the inputs used in the peaker methodology for large QFs on a quarterly basis to more accurately reflect the Companies’ most current forecast of avoided costs. (Tr. Vol. 2, pp. 390.17-.19, 390.31-.32.)

Specific to calculating forecasted avoided capacity value, Witness Snider testified that a central tenet of PURPA provides that customers should not be required to pay QFs for avoided capacity unless the QF is actually offsetting a future avoidable capacity need of the utility. (Tr. Vol. 2, p. 390.21.) Witness Snider explained how the timing of the utilities’ need for incremental generating capacity impacts the calculation of the avoided capacity payment, in that the annual fixed capacity costs used in the avoided cost rate calculation include the annual fixed capacity costs starting with the first year in which an actual avoidable capacity need exists, as determined by the utility’s IRP. (*Id.*) He further explained that a utility’s capacity need must be actually

avoidable in order to meet the FERC requirement that avoided cost rates be calculated to reflect the cost the utility would pay for capacity “but for” the QF. (Tr. Vol. 2, pp. 390.21-.22.) He also testified that recognizing the utility’s need for capacity the calculation is fair to the utility customers and the QFs because the customers only pay capacity payments to QFs that are equal to the economic value of the utility’s actual avoided capacity cost. (Tr. Vol. 2, p. 23.)

Witness Snider noted that the Commission approved the Companies’ standardized methodology for projecting avoided capacity need in Order No. 2019-881(A). He also noted that the NCUC approved this approach in Docket No. E-100, Sub 148. (*Id.*)

Witness Snider explained that at the time Cherokee submitted its September 2018 offer to sell its power to DEC for a new PPA term commencing in 2021, DEC’s first avoidable capacity need as identified in its 2018 IRP was projected to arise in 2028, and at the time that Cherokee submitted its December 12, 2018 communication to DEP, DEP’s first avoidable capacity need as identified in its 2018 IRP was projected to arise much earlier in 2020. (Tr. Vol. 2, p. 390.24.) He also explained that DEC took steps in October 2018 to meet its near term need for capacity by procuring capacity and energy through a non-PURPA competitive market solicitation. Cherokee participated in that non-PURPA competitive market solicitation, but was not successful as its bid exceeded all other bidders. (Tr. Vol. 2, pp. 390.23-.25.)

Witness Snider also explained why certain near-term capacity additions identified in the DEC 2018 IRP could not be avoided by the Cherokee Facility, as suggested by Witness Strunk. (Tr. Vol. 2, pp. 390.26-.27.) Witness Snider described in detail the process the Companies use to identify when an avoidable capacity need arises, under which the first avoidable need is determined by considering only designated resource in this plan while excluding all undesignated future resources, which are assumed to be avoidable. (Tr. Vol. 2, p. 390.27.) He stated that the Lincoln

CT received a CPCN from the NCUC in 2017, prior to the time Cherokee asked for avoided cost rates, and, therefore, was a “designated” resource in 2018 and did not represent an avoidable capacity resource. (Tr. Vol. 2, p. 390.28.) He also testified that the Bad Creek uprates exemplify a situation where uprates are conducted in the normal course of business, as part of major maintenance schedules, that cannot be avoided by a new QF once the projects are funded and under way and, therefore, are also not undesigned or avoidable. (*Id.*) In addition, he noted that the Bad Creek uprates were identified by DEC as far back as its 2016 IRP, long before the negotiations for the Cherokee PPA commenced in late 2018. (Tr. Vol. 2, p. 390.27-.29.)

Witness Freund also testified that DEC and DEP consistently used the peaker methodology to calculate the avoided cost rates offered to Cherokee. (Tr. Vol. 2, p. 390.17.) DEC/DEP Witness Freund’s Figure 1 presented the key attributes of each rate provided to Cherokee during the 2018-2021 time period. (Tr. Vol. 2, p. 338.5.) Witness Freund testified that both Companies responded multiple times to Cherokee’s requests for avoided cost rates, and that each rate, regardless of whether it reflected a dispatchable-tolling or a non-dispatchable PPA structure, was based on then-current inputs in a manner consistent with the Commission’s directives to the Companies in its recent avoided cost proceeding and with the approach used by the Companies to calculate avoided cost rates for large QFs. (Tr. Vol. 2, p. 338.6.) He explained that prior to the 2019 avoided cost proceeding, the Commission directed that all rates for QFs above 2 MW or that were otherwise ineligible for standard tariffs be negotiated under PURPA and FERC’s implementing regulations. (*Id.*) Witness Snider noted the Commission’s recent approval of the Companies’ methodology for calculating avoided cost rates in Order No. 2019-881(A) and order on clarification, Order No. 2020-315 also instructed the Companies to regularly update inputs for avoided energy and capacity when calculating rates available to large QFs, and accepted the Companies’ payment for capacity

based on the first year of need as identified in their recent IRPs. (Tr. Vol. 2, pp. 390.19, .23.) Witness Freund testified that both DEC and DEP followed their standardized process for calculating rates for large QFs of using the most current inputs and assumptions of avoided capacity and energy needs to calculate avoided costs as of the time the QF offers to sell power to DEC or DEP. (Tr. Vol. 2, pp. 338.4-.8.) Witness Freund also compared and contrasted a dispatchable tolling agreement structure from a non-dispatchable “must-take” contract. (Tr. Vol. 2, pp. 338.8-.9.)

Witness Freund disagreed with Witness Strunk’s proposed avoided cost rate, testifying that the rate calculations greatly over-simplified the avoided cost rate determination, did not properly account for start cost payments that DEC makes to Cherokee under the 2012 PPA, and improperly included capacity payments prior to DEC’s first year of capacity need. He concluded that Witness Strunk’s simplified rate proposal exceeded DEC’s avoided cost, even if a September 2018 LEO were assumed. (Tr. Vol. 2, pp. 338.11-.15.) Witness Freund testified that while each of the rates provided to Cherokee was accurate and appropriate at the time they were calculated, currently the most accurate and appropriate rates for Cherokee are those provided in February 2021, as they reflect DEC’s avoided cost at the time of the original expiration of the 2012 PPA. (Tr. Vol. 2, p. 338.15-.16.)

On behalf of ORS, Witness Hipp recommended that the successor PPA for Cherokee limit avoided energy and capacity payments to Cherokee at or below the actual avoided costs calculated based on the Commission-approved methodology. She explained that the “ceiling” for energy and capacity payments to a QF is one based on the utility’s actual avoided costs, and noted that DEC’s customers are currently paying significantly more than DEC’s actual avoided costs under the extensions of the 2012 PPA. (Tr. Vol. 3, pp. 568.5-.6.)

Witness Hipp also explained that the Commission approved two temporary extensions of the 2012 PPA for the time period of January 1 through August 28, 2021, and that ORS objected to the most recent temporary extension of the 2012 PPA due to the absence of proper safeguards to protect DEC's customers from excessive purchased power costs. (Tr. Vol. 3, p. 568.6.) She testified to ORS's position that Cherokee should bear the economic risk of any extensions of the 2012 PPA and recommended that in the event the Commission determines that going forward the price paid under a successor PPA is less than the price paid under the 2012 PPA, the dollar amount attributed to the incremental overpayment to Cherokee due to the extension of the terms of the 2012 PPA be credited or refunded to DEC customers in a manner determined by the Commission. (Tr. Vol. 3, pp. 568.6-.7.) She suggested that the credit or refund to customers can be accomplished through lower payments to Cherokee under the successor PPA. (*Id.*) Witness Keen testified that Cherokee previously executed a \$1 million letter of credit, and DEC has requested that Cherokee increase the letter of credit to a total of \$3 million on or before August 10, 2021, and to a total of \$6 million on or before September 10, 2021 to cover the likely overpayment resulting from the two temporary extensions. (Tr. Vol. 2, p. 242.116; Hrg. Ex. 22.) On behalf of Cherokee, Witness Hanson testified that Cherokee has agreed to increase the letter of credit to \$3 million on or before August 10, 2021, but that it has not agreed to the second increase. (Tr. Vol. 3, p. 671.)

ALLEGATIONS OF BAD FAITH NEGOTIATIONS

Cherokee's complaint alleged that the Companies refused to negotiate in good faith and enter into a new PPA with Cherokee. (Complaint, p. 1.) Witness Hanson claimed that DEC did not engage with Cherokee in good faith because it did not recognize Cherokee had established a LEO, refused to acknowledge the history of DEC's relationship with Cherokee Facility, or provide support for its proposed rates. (Tr. Vol. 3, p. 660.2.) Witness Strunk claimed that DEC did not

act in good faith because the rates offered to Cherokee in October 2018 did not reflect the most recent Commission order on avoided costs or reasonably follow FERC's implementing regulations. (Tr. Vol. 3, p. 498.5.)

The Companies' witnesses countered that DEC and DEP followed a standardized methodology for calculating avoided cost rates and standardized process for offering avoided cost rates to Cherokee, treated Cherokee like all other large QFs in a non-discriminatory manner, and, at all times, acted in good faith in their dealings with Cherokee to negotiate with Cherokee in the interests of the Companies' customers and in a manner consistent with PURPA and the Commission's implementing orders. As summarized above, the DEC/DEP Witnesses explained that during the 2018-2021 time period Cherokee pursued three different but overlapping avenues in an attempt to negotiate rates higher than the Companies' actual avoided costs, and the Companies consistently responded to Cherokee's requests for information to support the rate calculations, and attempted to work with Cherokee on all three paths in good faith. Witness Keen states that his detailed timeline and supporting documentation demonstrate the Companies' efforts to be transparent with Cherokee and to offer a PURPA-compliant successor PPA for the Cherokee Facility and that DEC/DEP did not obstruct negotiations or refuse to negotiate in good faith. (Tr. Vol. 2, pp. 242.9-.10.)

Witness Hanson also asserted that DEC and DEP acted in bad faith by not providing sufficient support for the rates provided to Cherokee and claimed that the Companies' failure to provide a meaningful explanation stymied Cherokee's ability to obtain a successor PPA. (Tr. Vol. 1, pp. 15.20-.23; Tr. Vol. 3, pp. 660.3, .17.) However, at the hearing, Witness Hanson conceded that DEC and DEP had responded in writing to each and every offer to sell and request for information made by LS Power and Cherokee. (Tr. Vol. 1, p. 76.) DEC's October 5, 2018 letter

to Cherokee responded to Cherokee's September 17, 2018 offer to sell energy and capacity to DEC. (Tr. Vol. 1, p. 36.) DEP similarly responded to Cherokee's December 12, 2018 offer to sell to DEP. (Tr. Vol. 1, p. 51.). He also agreed that DEP's June 24, 2020 avoided cost pricing responded to Cherokee's request for rates dated May 4, 2020. (Tr. Vol. 1, p. 55.) Specific to Cherokee's request for supporting detail regarding the offered avoided cost rates, on June 14, 2019, the Companies responded to Cherokee's April 30, 2019 request for information regarding DEC's and DEP's rates provided in October 2018 and February 2019. (Tr. Vol. 1, p. 67-68.) On August 20, 2020, DEP again responded in writing to each of Cherokee's twelve requests for information and support for the DEP avoided cost rates provided in June 2020. (Hrg. Ex. 13 (Attachment 17).)

Witness Keen testified that—as the individual directly responsible for negotiating with Cherokee—that the Companies acted in good faith in their communications with Cherokee and were consistently responsive to LS Power's requests for information to support DEC/DEP's rate calculations. Moreover, Witness Keen explained that the Companies responses were in line with DEC's and DEP's responses to similar requests for supporting information regarding avoided cost rate calculations. (Tr. Vol. 2, pp. 242.9, .17; *see also* Hrg. Ex. 13 (Attachments 12 & 17).) Similarly, Witness Freund testified that the Companies provided similar levels of rate support to Cherokee as to other large QFs, and in addition that DEC/DEP's responses to Cherokee's discovery requests since the Complaint was filed involved providing very detailed input and output data related to modeling and other supporting calculations. (Tr. Vol. 2, pp. 338.10-.11.) Witness Snider also testified that the Companies were transparent with regard to avoided cost rate information provided to Cherokee as required by Act 62 and the Commission. (Tr. Vol. 2, p. 390.36.) Accordingly, the Companies' witnesses disputed Cherokee's allegations that DEC and DEP had not been responsive to Cherokee or had in any way acted in bad faith.

OPTION TO TRANSMIT AND SELL POWER TO DEP

Witness Hanson testified that PURPA allows QFs to sell their output either to an interconnecting utility or to another utility, and asserted that DEP frustrated Cherokee's effort to transmit and sell its power to DEP. (Tr. Vol. 2, pp. 15.7, .16; Tr. Vol. 3, pp. 660.12-.13.) In response to these allegations, DEC/DEP Witness Bowman recognized that Cherokee has a right to sell its power to DEP under PURPA and explained that, if Cherokee elects to sell its power to DEP under PURPA (and Cherokee makes arrangements to actually deliver its capacity and energy to DEP), DEP must purchase Cherokee's power at its avoided cost just like it would if Cherokee was directly connected to DEP. (Tr. Vol. 3, pp. 502.30-.31.) She emphasized that it is Cherokee's obligation to arrange for transmission service from DEC under the Companies' open access transmission tariff ("OATT") to deliver its power out of DEC to DEP, as recognized by FERC in *Kootenai Elec. Coop. Inc.*, 143 FERC ¶ 61,232 at PP 1, 33 (2013). (Tr. Vol. 3, p. 502.32.) She noted that DEC and DEP remain separate electric utilities operating separate power systems with separate and distinct transmission systems and separate avoided costs. She testified that Cherokee did not submit a transmission service request to DEC under the OATT to deliver its power to DEP. She also clarified that any dispute Cherokee may have about transmission service under the Companies' OATT would come under FERC's jurisdiction and be governed by the Companies' OATT. (Tr. Vol. 3, pp. 502.32-.33.)

LATE-FILED EXHIBIT AND MOTION TO STRIKE CHEROKEE RESPONSE

At the July 29, 2021 hearing, Commissioner C. Williams asked DEC/DEP Witness Freund to "update" his Figure 1 presented in his pre-filed direct testimony. As originally prepared, Figure 1 presented each of the five avoided cost rated proposals provided to Cherokee—in October 2018 (DEC), February 2019 (DEP), June 2020 (DEP), September 2020 (DEC), and February 2021

(DEC)—and described the characteristics of each rate proposal, including the date of rate request, date rate provided, PPA structure, IRP used to support first year of capacity need, first year of capacity need based on IRP, timing of gas cost assumptions, and term. (Tr. Vol. 2, p. 338.5.) Commissioner C. Williams asked Witness Freund to “add, where it is possible, what the Duke avoided energy value, avoided capacity value, and [what] the avoided cost is.” (Tr. Vol. 2, p. 384.) Clarifying her request, Commissioner C. Williams explained that she wanted “to be able to see the avoided energy and the avoided capacity cost and then the total avoided cost for as many of these . . . proposed contracts as [DEC and/or DEP] have offered on Mr. Freund’s Figure 1.” (Tr. Vol. 2, p. 387.) In other words, Commissioner C. Williams asked the Companies to supplement Witness Freund’s Figure 1 with information that was already prepared and in the record, but did not request the Companies make any new calculations and/or provide any new material that was not already in the record.

In response, DEC and DEP submitted Late-Filed Exhibit One on August 4, 2021, followed by a corrected version of Late-Filed Exhibit One on August 6, 2021 (the “LFE”). As directed by Commissioner C. Williams, the LFE appended on to Witness Freund’s Figure 1 DEC’s avoided cost rates as calculated in October 2018, September 2020, and February 2021. So that the numbers presented an apples-to-apples comparison of rates, for the DEC October 2018 entries, the Companies used the avoided cost components for a 10-year dispatchable tolling agreement capacity rate (rather than the 5-year “must-take” structure it originally offered to Cherokee) and as produced to the ORS in response to ORS Date Request No. 2-2 and as referenced by Witness Freund in his live testimony. (Tr. Vol. 2, p. 70.) The Companies did not provide rate calculations for the DEP February 2019 and June 2020 offers because DEP has never modeled a dispatchable tolling agreement for Cherokee based on inputs from December 2019 or June 2020. In other

words, each of the avoided cost rates included in the Companies' LFE were previously calculated and the LFE presented these rate proposals as 10-year dispatchable tolling agreements in response to Commissioner C. Williams' request.

Cherokee filed its Response to the LFE (the "Response") on August 12, 2021, and the Companies moved to strike the Response on August 18, 2021 on the grounds that it goes beyond the scope of Commissioner C. Williams' request and has not been subject to discovery and cross-examination. As the Companies explained in their brief in support of their Motion to Strike, Cherokee's Response is a 12-page single-spaced document that offers significant new analysis and purports to have calculated new avoided energy rates using a PLEXOS production cost simulation that was not requested by the Commission and was completed by Witness Strunk after the hearing. The results of Cherokee's new modeling purportedly yielded avoided energy rates that are more than double the avoided energy rates previously presented by Witness Strunk for Fall 2018 and nearly three times DEC's actual avoided costs as presented in its LFE. The Companies argued that it was improper for Cherokee to include this new analysis in a post-hearing filing as neither the Companies nor ORS have had an opportunity to conduct discovery on the modeling and/or to cross-examine Cherokee's witnesses on the newly proposed rates.

The Commission finds that post-hearing filings like late-filed exhibits and responses thereto must be appropriately limited such that they supplement the record of a proceeding without unduly prejudicing the rights of other parties. *See Dangerfield v. State*, 376 S.C. 176, 179, 656 S.E.2d 352, 354 (2008) ("The procedural component of the state and federal due process clauses requires the individual whose property or liberty interests are affected . . . the opportunity to introduce evidence, the right to confront and cross-examine adverse witnesses, and the right to meaningful judicial review."); *see also Utils. Serv. of S.C., Inc. v. S.C. Office of Regulatory Staff*,

392 S.C. 96, 107, 708 S.E.2d 755, 761 (2011) (finding that utilities must be given a “meaningful opportunity” to respond to evidence presented by other parties). As we have previously held, post-hearing filings that go “beyond the scope of the request and [have] not been subject to discovery and cross-examination” are improper for submission into the record. *In the Matter of Dominion Energy South Carolina, Inc.’s Request for Approval of an Expanded Portfolio of Demand Side Management Programs and a Modified Demand Side Management Rider*, Dkt. No. 2019-239-E, Commission Directive (Dec. 10, 2019) (striking from the record a late-filed exhibit that was overly broad and had not been subject to discovery and cross-examination).

Here, the Commission finds that Cherokee’s Response is overbroad, and goes beyond the scope of the comments contemplated by the Commission. Cherokee’s twelve-page Response presents entirely novel arguments based on newly-run modeling not requested by the Commission, challenges DEC’s avoided energy rate calculations for the first time, and proposes avoided energy rates that are *significantly higher* than any prior calculation vetted in this proceeding.

The Commission finds that Cherokee could have made each of these arguments in its pre-filed testimony. By waiting to argue these points in a post-hearing filing, Cherokee has deprived the Companies of their due process rights, and has ensured that neither the Companies nor ORS will have an opportunity to conduct discovery on the new modeling methodology or to cross-examine Cherokee’s witnesses on their newly asserted positions. For all of these reasons, the Commission concludes that the portions of Cherokee’s Response that were highlighted in Attachment A to the Companies’ Motion to Strike should be stricken from the record as overly broad and improperly- and late-filed evidence that has not been subject to discovery and cross examination.

CONCLUSIONS

The Commission has jurisdiction over this Complaint and is responsible for implementing PURPA in South Carolina. 16 U.S.C. § 824a-3(f); S.C. Code Ann. § 58-41-20(A). The Commission's responsibility for implementing PURPA includes ensuring that utilities act in good faith and afford QFs with reasonable opportunities to exercise their rights to sell their power under PURPA and, in turn, that the avoided cost rates that utilities calculate and offer to QFs are non-discriminatory towards the QF and just and reasonable to the utility's customers and in the public interest. 18 C.F.R. § 292.304(a); S.C. Code Ann. § 58-41-20(A). The Commission agrees with DEC/DEP Witnesses Bowman and Snider that avoided cost rates authorized by this Commission in implementing PURPA are based upon the utility's system costs and are not intended to subsidize QFs or to compensate QFs in excess of the incremental cost of alternative energy that the utility can generate or purchase from another generating source. 16 U.S.C. § 824a-3(d). (Tr. Vol. 3, p. 502.7, Tr. Vol. 2, p. 390.6.) The Commission is also responsible under Act 62 with overseeing the methodology that DEC and DEP use to calculate avoided costs and, in doing so, is responsible for protecting customers from unjust and unreasonable rates by striving to reduce the risk placed on the using and consuming public associated with QFs contracts. These legal requirements and the Commission's recent Order Nos. 2019-881(A) and 2020-315 approving avoided cost rates and methodologies for DEC and DEP as well as prior orders including Order Nos. 2016-439 and 85-347 requiring negotiations between utilities and larger QFs inform the Commission's determination in this proceeding.

Before addressing the appropriate rates and terms for a new PPA to be offered to Cherokee, the Commission initially finds that the rates and terms under the 2012 PPA now significantly exceed DEC's current avoided cost of capacity and energy and are no longer just and reasonable

to DEC's customers. At Cherokee's request, the Commission has granted two interim extensions of the 2012 PPA since January 1, 2021, when the 2012 PPA's term was scheduled to expire. In both Order No. 2020-846 dated December 30, 2020, and Order No. 2021-294, extending DEC's interim obligation to continue to pay Cherokee under the now-very-stale 2012 PPA rates through August 28, 2021, the Commission conditioned its approval by reserving the right to consider whether or not it is appropriate to subject the rates paid during this additional extension period to true-up. Order No. 2021-294 also specifically found that Cherokee should bear the economic risk of any possible overpayment from extension of the 2012 PPA. Based on the evidence presented in this proceeding, all avoided cost rates offered by DEC during the recent period of negotiations as well as the alternative recommendations presented by Cherokee are well below—at minimum 24 percent below—the 2012 PPA rates that the Commission has ordered DEC and its customers to continue to pay in 2021. (Tr. Vol. 3, p. 628.)

Based upon the foregoing, the Commission orders DEC to calculate the overpayment amount owed by Cherokee based upon the difference between interim rates paid under the Commission-ordered extensions of the 2012 PPA and the avoided cost rates included in the February 10, 2021 dispatchable tolling agreement term sheet offered to Cherokee, as discussed further below. In order to ensure that Customers are not responsible for the economic risk of this overpayment amount, the plan to compensate customers for the overpayment, either through reductions in ongoing payments to Cherokee or otherwise, must include carrying costs calculated to make customers whole for the time period between collection of the overpayments and the refund. Cherokee shall provide DEC sufficient financial security to hold DEC's customers harmless and bear the economic risk of any outstanding refunding obligation stemming from the overpayment under the extension of the 2012 PPA. DEC shall provide the Commission written

notice within five (5) days of Cherokee's full and complete repayment of the overpayment amount, which shall be subject to audit by the ORS. DEC shall also retain all its contractual rights under the 2012 PPA, including the right to hold Cherokee in Default if Cherokee fails to timely meet its overpayment obligations.

Turning to the issues requiring Commission resolution to enable the parties to move forward toward execution of a new PPA, the Commission must determine:

1. Whether Cherokee's actions in the fall of 2018 warrant the Commission establishing a non-contractual LEO based on a finding that LS Power legally obligated Cherokee to sell its power to DEC in September 2018;
2. Whether DEC's and DEP's application of the standardized peaker methodology appropriately recognized each utility's first year of capacity need and reasonably calculated avoided cost rates offered to Cherokee; and
3. To the extent Cherokee alternatively intends to sell output to DEP, whether Cherokee met its obligation under PURPA to obtain transmission service from DEC to deliver its power to DEP in order to be paid DEP's avoided costs.

Considering all of the evidence in the record as well as the applicable law, the Commission finds as follows:

I. Issue 1: Cherokee Did Not Establish a Non-Contractual LEO with DEC in Fall 2018

On the first issue, we conclude based upon all of the evidence in the record that Cherokee in the fall of 2018 (i) did not exercise its rights to contractually obligate itself through execution of a PPA with either DEC or DEP at the utility's avoided cost; and (ii) has not demonstrated that the Commission should recognize a non-contractual LEO in the absence of a PPA because Cherokee did not make a legally enforceable commitment that obligated the QF to sell power to either company over a future term at the utility's avoided costs. In support of these conclusions we rely on the following evidence.

First, Cherokee attempted to sell full capacity and energy output to multiple utilities. A QF cannot make a legally binding commitment to sell *all* of its capacity and energy to more than one utility at the same time. Accordingly, and because DEC and DEP are separately regulated entities and separate electric utilities under PURPA, Cherokee's actions of shifting between "legally enforceable offers" to the two utilities underscores that these purported commitments were non-binding and unenforceable as neither DEC nor DEP had any legally enforceable rights to the Cherokee Facility's output and could not count on output from the Cherokee Facility in their respective resource planning to serve customers after the 2012 PPA expired. Cherokee's actions demonstrate that it was free to, and in fact did, "walk away" from its purported commitment to DEC without consequence, and then effectively rejected DEC's avoided cost rates. As noted in the Companies' Post-Hearing Brief, the Commission has previously rejected arguments that a QF established a LEO when the QF had not actually committed itself and could walk away from its offer to sell power. *Pacolet River Power Co., Inc. v. Duke Power Co.*, Order on Remand Dismissing and Denying Complaint, Dkt. No. 95-1202-E, Order No. 2001-663 (Jul. 24, 2001) ("because Pacolet was free to walk away from the negotiations without liability, . . . no 'legally enforceable obligation' was created"). Accepting a non-contractual LEO as being formed in these circumstance would be inconsistent with FERC's (and this Commission's) expectation that a QF must actually commit itself to sell to an electric utility to form a LEO and would be contrary to the express goals in Order No. 872, as explained by DEC/DEP Witness Bowman.

Second, Cherokee's initial actions of sending a non-binding letter and modifying an otherwise inapplicable Notice of Commitment Form did not create a legally enforceable obligation. Attachment of the Notice of Commitment Forms to Cherokee's letters did not meaningfully increase the level of Cherokee's offer to sell power. The forms were intended for

use by North Carolina QFs less than 5 MW in size attempting to sell output to DEC or DEP in North Carolina. Cherokee made significant modifications to this otherwise inappropriate form, to accommodate Cherokee's 98 MW facility and adjusting the jurisdiction from North Carolina to South Carolina.

Third, the actual terms of the modified Notice of Commitment Form Cherokee submitted—even if establishing a commitment—did not act to preserve Cherokee's right to sell its output in perpetuity. The Notice of Commitment Form approved for use in North Carolina does not create an open-ended right to the utility's avoided cost without further action by the QF to memorialize its initial commitment through timely execution of a PPA. Section 6 of the Notice of Commitment Form delivered by Cherokee provided that avoided cost rates under the Notice of Commitment Form would expire 30 days after the utility delivered an executable PPA to the QF if the QF failed to contractually obligate itself to sell and deliver power over a future term. This reasonable limit on the time in which a QF can execute a PPA to contractually memorialize its Notice of Commitment Form also aligned with the standardized process DEC followed with Cherokee in the fall of 2018, allowing the parties 60 days from the date of delivery of avoided cost rates and executable form of PPA to finalize any negotiations or the avoided cost rates would become stale and expire. (Tr. Vol. 2, pp. 390.11, 390.31-.32.)

Fourth, as additional evidence of its lack of serious commitment to DEC or DEP, Cherokee never accepted either Company's calculated avoided cost rates. By rejecting each of the Companies' five offers of avoided cost rates and PPAs and making counter offers at rates well above the Companies' avoided costs, (*see* H. Ex. 13, at 9 (Attachment 8)), Cherokee's claim of a LEO is inconsistent with FERC's regulations and PURPA requiring a QF to make a legally enforceable obligation to deliver power *at the utility's' avoided cost*. While DEC and DEP

followed the Companies' standardized process for negotiating and finalizing PPAs with Large QFs, Cherokee did not actively pursue meaningful discussions with DEC or later DEP to execute a new PPA.

Fifth, while Cherokee repeatedly alleges that the Companies delayed the negotiation process, the undisputed evidence confirms that Cherokee did not diligently pursue a successor PPA. Cherokee waited six months from the date it first received DEC's rates to ask for any information supporting those rates, (Hrg. Ex. 13, at 50-51 (Attachment 12)), and nearly nine months from receiving the Companies' response to take any further action toward a successor PPA. (Tr. Vol. 2, pp. 332-33.) These delays by Cherokee show that it did not diligently pursue a new PPA with DEC or DEP after each utility had provided its avoided cost rates and form of PPA to Cherokee for review and execution.

In addition, although claiming to have suffered hardship because the Companies "refused" to provide sufficient data supporting their rate calculations, Cherokee failed to ever follow up to question the Companies' use of the peaker methodology to calculate avoided cost rates and failed to take timely action to seek Commission review of the methodology. Cherokee did not intervene in either the Companies' 2019 or 2021 avoided cost proceedings to challenge the appropriate approach for calculation of avoided cost rates. Since the Commission is tasked under Act 62 with approving the Companies' avoided cost methodology in biennial avoided cost proceedings, that clearly would have been the appropriate forum for Cherokee to propose an alternate methodology or to seek a reversal of the Commission's position on capacity payments in the absence of a forecasted IRP capacity need. Rather than proactively pursuing any of these options that would have provided for timely resolution between the parties, Cherokee instead did nothing to advance its position and, instead, made unsolicited counter-offers asking the Companies to pay Cherokee

rates that were not calculated consistently with the Commission-approved peaker methodology and were above the utility's avoided cost.

Sixth and finally, Cherokee filed its complaint more than two years after it purports to have established LEO. Cherokee never engaged with ORS to attempt to resolve its concerns, nor did it file the Complaint during a time period that might reasonably lead to a resolution in advance of the December 31, 2020 termination of the 2012 PPA. Instead, Cherokee waited until the eleventh hour—over two years after Cherokee asserts it established a LEO with DEC—to file its Complaint and seek relief from the Commission.

In sum, we conclude that Cherokee's actions served only to commence negotiations by making a "legally enforceable *offer*"—not obligation—as stated in Cherokee's letter. However, this offer was not binding on Cherokee, and Cherokee's act of filling out a modified, unapproved Notice of Commitment Form did not create a LEO or bind Cherokee to sell to DEC in any way. As recognized by DEC's October 5, 2018 response letter, Cherokee's written notice of its intent to sell power for a new contract term was the first step in "commenc[ing] negotiations[.]" (Hrg. Ex. 13, at 17 (Timeline Attachment 3).) DEC took the second step by "deliver[ing] its avoided costs as well as a form PPA that DEC would agree to execute in order to establish a legally binding arrangement to purchase Cherokee's full output of energy and capacity over a five-year term commencing on January 1, 2021." (*Id.*) Cherokee then failed to progress those negotiations and to do everything within its power to create such an obligation. Accordingly, no legally enforceable obligation was created in September 2018.

We also conclude that the course of dealing between DEC/DEP and Cherokee does not show that DEC or DEP created barriers to Cherokee's ability to sell or support Cherokee's assertions that DEC/DEP refused to buy Cherokee's power at avoided cost. In contrast to

Cherokee's claims that DEC and DEP failed to negotiate a successor PPA in good faith in the fall of 2018, the facts and extensive correspondence between the parties demonstrate that DEC followed a standardized methodology and process to calculate avoided cost rates using the peaker methodology and to then deliver those rates and a form PPA that DEC was prepared to execute if Cherokee desired to contractually obligate itself to a new contract. No evidence was presented that DEC or DEP were discriminatory or imposed any barriers that would have precluded Cherokee from signing a PURPA PPA with either DEC or DEP. Instead, the facts and correspondence show that it was Cherokee that was unwilling to commit to sell its power at DEC's avoided costs and, instead of engaging in negotiations with DEC, Cherokee began looking for a better PURPA deal to sell its power to DEP in December 2018.

II. Issue 2: DEC and DEP Reasonably and Appropriately Calculated Avoided Cost Rates Using Commission-Approved Methodology

Turning to the second issue, we conclude that each of the avoided cost rates provided by the Companies to Cherokee were consistent with PURPA, FERC's implementing regulations, Act 62, and the methodology recently approved by the Commission in Order No. 2019-881(A) for use in calculating avoided cost rates for large QFs.

Consistent with ORS Witness Hipp's testimony, the Commission specifically finds that it was appropriate for DEC and later DEP to utilize a standardized and now Commission-approved peaker methodology to calculate avoided cost rates for Cherokee. (Tr. Vol. 3, p. 568.5.) Cherokee has not presented any evidence to suggest that DEC has not followed the standardized Commission-approved peaker methodology. As explained by DEC/DEP Witness Snider the Companies consistently apply the peaker methodology in calculating avoided cost rates for all large QFs taking into account the utility's first year of capacity need based upon the utility's IRP and then levelizing the capacity value of a QF's power over a future contract term. (Tr. Vol. 2,

pp. 390.22-.23.) The Commission extensively reviewed this methodology in DEC’s and DEP’s initial 2019 avoided cost proceedings under Act 62, and Order No. 2019-881(A) specifically found that methodology reasonably and appropriately calculated avoided capacity costs based on each utility’s projected first year of capacity need in its current IRP and further found that “customers should not be required to pay . . . QFs for capacity prior to the first year in which it is needed to serve system load[.]” Order No. 2019-881(A), at 89, 91-92.

While not controlling on this Commission, the Commission also finds persuasive that the NCUC has similarly approved DEC’s and DEP’s application of the peaker methodology and approach to projecting avoided capacity need for use in calculating avoided cost rates during period at issue. In October 2017, approximately one year before DEC offered its avoided cost rates and terms to Cherokee, the NCUC held that “when calculating avoided capacity rates using the peaker methodology, it is appropriate to require a payment for capacity in years of a utility’s integrated resource planning (IRP) forecast period when a capacity need is demonstrated during that period.” *See Order Establishing Standard Rates*, N.C.U.C. Docket No. E-100, Sub 148 at 6-7, (Oct. 11, 2017). The NCUC further held that inclusion of zero capacity value in avoided capacity rates until the utility’s IRP shows a need is appropriate and not discriminatory as “PURPA was not intended to force a utility and its customers to pay for capacity that it otherwise does not need.” *Id.* at 48-49. The NCUC’s guidance aligns with the methodology approved by this Commission in Order No. 2019-881(A) discussed above.

In October 2018, when Cherokee communicated its intent to sell to DEC, DEC’s most current IRP did not identify any avoidable capacity need during the five-year term that DEC offered to all large QFs at that time. If Cherokee found fault in the rates or terms offered by DEC in fall of 2018, it had the option to seek assistance from ORS to resolve those concerns or to more

timely file a complaint with the Commission. Cherokee failed to take any such action and the Commission finds no improper or discriminatory conduct by DEC (or later DEP) in calculating avoided capacity costs based upon the Commission-approved methodology.

We also conclude that the avoided cost rates calculated by Cherokee Witness Strunk are inappropriate and not reflective of DEC's avoided capacity costs. Witness Strunk's proposal accepted the avoided energy offered by DEC in October 2018, but proposed to significantly increase the avoided capacity rates based on the avoided capacity values in DEC's standard offer tariff rates summarily approved over two years earlier in Order No. 2016 -349. This proposal is not persuasive and would not be just and reasonable to customers or in the public interest for a number of reasons. First, Order No. 2016 -349 is clear that the Commission accepted the standard offer tariffs agreed to between the Companies, ORS, and other intervenors in that proceeding for small QFs eligible for the standard offer tariff, but did not investigate or approve the methodology used to calculate DEC's and DEP's standard offer avoided cost rates. The rates approved in Order No. 2016-349 did not apply to large QFs and this 2016 Order preceded Act 62 where the General Assembly specifically directed the Commission to investigate and approve the utility's avoided cost rate methodology.

Second, the Commission disagrees with Witness Strunk that it was discriminatory for DEC to use more current inputs and assumptions for Cherokee versus the standard offer rates available to small QFs at the time. The Cherokee Facility is a 98 MW cogeneration QF, meaning that it exceeds the size limit for standard offer eligibility by nearly 50 times and also exceeds the 80 MW limit applicable to small power producer QFs. Cherokee is not and has never been eligible for the standard offer rates. Therefore, the standard offer rates approved in 2016 do not establish the avoided cost rates and terms appropriate for Cherokee.

Third, it would be unjust and unreasonable to rely upon inputs and assumptions from 2016 (or earlier) in calculating avoided cost rates for a large QF like Cherokee for power to be delivered approximately five years later in 2021. The Commission emphasized the importance of using current inputs and assumptions in calculating avoided cost rates for large QFs in Order No. 2019-881(A) “find[ing] that it is appropriate for DEC and DEP to continue the practice of applying the most up-to-date inputs under the peaker methodology in calculating such rates for large, non-Standard PPA QFs,” Order No. 2019-881(A) at 81-82, and again in Order No. 2020-315(A) “find[ing] and conclud[ing] that Duke should routinely update its inputs for both avoided energy and avoided capacity costs based upon each Company’s most current integrated resource planning assumptions and forecasts when calculating avoided energy and capacity cost rates available to Large QFs.” Order No. 2020-315(A) at 19. Moreover, the history of DEC’s and DEP’s PURPA implementation demonstrates that these increasingly-stale avoided cost rates were no longer accurate and appropriate as of fall 2018, as DEC and DEP jointly filed an application to update their standard offer avoided cost rates on November 30, 2018 in Docket No. 1995- 1192-E. Finally, the Commission finds that Witness Strunk’s proposal would be inappropriate because it would, in fact, introduce discrimination between QFs by requiring DEC to deviate from the avoided cost methodology used to calculate avoided capacity rates for all other QFs and would compensate Cherokee more than other QFs for its power. The Commission declines to adopt this proposal.

Based on the evidence presented, the Commission concludes that the most accurate and appropriate avoided cost rates for Cherokee under a successor PPA are the rates provided by DEC on February 10, 2021, attached to this Order as Attachment 1. As discussed above, the Commission finds that Cherokee’s conduct did not create legally enforceable commitment prior

to filing its Complaint as it refused to accept either DEC's or DEP's avoided cost rates and failed to make any meaningful effort to negotiate the commercial terms of a new PPA. The February 2021 rates most accurately and appropriately reflect DEC's avoided cost rates at the time Cherokee filed its Complaint and at the time the 2012 PPA expired. The Companies' shift to a 10-year dispatchable tolling agreement for Cherokee after Act 62 was enacted is also reasonable, as Act 62 required ten-year contracts for certain small power production facilities. The Companies acted in good faith to extend this longer PPA term to Cherokee even though its facility is a cogeneration facility.

Based on the evidence presented, the Commission finds that the Companies acted reasonably and in good faith to evolve the avoided cost rates offered to Cherokee as regulatory circumstances evolved. While the 2012 PPA was a dispatchable tolling agreement, the Companies were offering all large QFs—of any generation type—5-year avoided cost rates and must-take contract structures in the fall of 2018. After the enactment of Act 62 and the Commission's issuance of Order No. 2019-881(A), the Companies offered Cherokee a 10-year dispatchable tolling agreement, appropriately taking into account the characteristics of the power supplied by the large QF in quantifying avoided costs. Order No. 2019-881(A), at 80. Based upon the positions of the Companies and Cherokee and non-opposition by ORS, the Commission finds that a 10-year dispatchable tolling agreement length and structure of the successor PPA is reasonable and appropriate.

Based on the evidence presented, including the testimony and the detailed timeline of correspondence between the parties, the Commission also finds no evidence of bad faith on the part of the Companies in this matter. Despite Cherokee's repeated claims to the contrary, the Commission concludes that there is no evidence that the Companies discriminated against

Cherokee or otherwise treated it differently than other large QFs. Cherokee is a large QF and therefore not entitled to standard rates and terms that are available to QFs with capacity 2 MW or less. Because Cherokee is a large QF, the Companies utilized their standard process and methodology for calculating avoided cost rates and negotiating PPAs, which has been approved by the Commission. The Companies therefore treated Cherokee like they treat all other large QFs. The Commission finds it notable that Cherokee never raised complaints about discriminatory treatment with ORS or the Commission, and did not intervene in any Commission proceeding relevant to PURPA implementation until more than two years after asserting an LEO with DEC.

The Commission also specifically finds Companies' efforts to provide reasonable information regarding the avoided cost rates inputs and methodology throughout the negotiations to have been reasonable. The evidence shows that the Companies unfailingly responded in a timely manner to Cherokee's requests for information supporting the avoided cost pricing provided to Cherokee. The Companies' witnesses testified that they provided standard information in support of those rates consistent with the level of detail that DEC and DEP have provided to other large QFs during negotiations. Finally, at no time did Cherokee communicate to the Companies or to ORS or the Commission that the information provided by DEC or DEP was insufficient until making such allegations in its complaint more than two years after the first rates were provided to Cherokee.

III. Issue 3: Cherokee Must Obtain Transmission Service from DEC to Wheel and Deliver Power to DEP in Order to Sell to DEP Under PURPA

Finally, on the third issue requiring Commission determination, we conclude with respect to wheeling to DEP that, in order to sell its output to DEP, Cherokee was responsible for obtaining the transmission service required to transmit its power from DEC to DEP. The Companies agree with Cherokee that PURPA provides QFs with the right to sell its output to any electric utility

obligated to purchase the QF's output under PURPA. However, it is the QF's responsibility to arrange transmission service to transport its energy from the generating facility to the non-interconnected utility. 18. C.F.R. 292.303(d); *Kootenai Elec. Coop. Inc.*, 143 FERC ¶ 61,232 at PP 1, 33 (2013)(explaining that "[a] utility is obligated under PURPA . . . to purchase the output of a QF, even a QF located in another state, as long as the QF can deliver its power to the utility" and the "QF has the discretion to choose to sell to a more distant utility . . . as long as the QF can deliver its power to the utility[.]"). We note that in FERC's recent denial of rehearing in ER21-304-002, FERC observed that Cherokee had offered no evidence that it requested transmission service to transmit its power over DEC's transmission system to deliver to another utility. *Cherokee County* 176 FERC ¶ 61,069 at P 12 (2021).

We also conclude that any disputes Cherokee may have regarding such an arrangement—including any issues regarding the designation of network resources—fall under the Companies' joint OATT and FERC's jurisdiction.

NOW, THEREFORE, IT IS HEREBY ORDERED THAT:

1. The Companies' Motion to Strike is granted. Any motions not expressly ruled upon herein are denied.
2. The relief requested in Cherokee's Complaint is hereby denied for the reasons discussed in this Order.
3. DEC shall offer to Cherokee the 10-year dispatchable tolling agreement avoided cost rates originally offered to Cherokee on February 10, 2021, which was based upon the Commission approved methodology, recognized Cherokee's dispatchability by offering a dispatchable tolling structure, and reasonably calculated avoided cost rates based upon the

Commission-approved peaker methodology as of the date of the Complaint and the end of the 2012 PPA's term on December 31, 2020.

4. Within thirty (30) days of the date of this Order, DEC shall deliver to Cherokee a ten-year dispatchable tolling agreement consistent with the rates and terms of the February 10, 2021 offer and the terms of the Commission-approved Large QF PPA adjusted, as appropriate, to reflect a dispatchable tolling agreement structure. The term of this new "2021 PPA" shall extend from January 1, 2021 to December 31, 2030. Cherokee shall have sixty (60) days from the date of delivery of the 2021 PPA to finalize and execute the 2021 PPA or Cherokee will be paid at DEC's as-available rate until such time as Cherokee commits to sell its output for a future contract term and associated avoided cost rate by executing a PPA. During the period from August 29, 2021 to either the date that Cherokee executes a new 2021 PPA or the date that the sixty (60) day period for negotiation of the new 2021 PPA expires, DEC shall pay Cherokee under the February 10, 2021 avoided cost rates approved by this Commission in this Order and the current capacity quantity of 86 MW.
5. Within thirty (30) days of the date of this Order, DEC shall calculate the overpayment amount owed by Cherokee based upon the difference between interim rates paid under the Commission-ordered extensions of the 2012 PPA and the avoided cost rates included in the February 10, 2021 offer through August 28, 2021. In order to ensure that Customers are not responsible for the economic risk of this overpayment amount, the plan to compensate customers for the overpayment, either through reductions in ongoing payments to Cherokee or otherwise, must include carrying costs calculated to make customers whole for the time period between collection of the overpayments and the refund. Cherokee shall provide DEC sufficient financial security to hold DEC's customers harmless and bear the

economic risk of any outstanding refunding obligation stemming from the overpayment under the extension of the 2012 PPA. DEC shall also retain all its contractual rights under the 2012 PPA, including the right to hold Cherokee in Default if Cherokee fails to timely meet its overpayment obligations.

6. DEC shall provide the Commission written notice within five (5) days of Cherokee's full and complete repayment of the overpayment amount.
7. DEC's calculation of the overpayment amount and Cherokee's repayment of such amounts shall be subject to audit by the ORS.
8. This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Chairman

ATTEST:

Executive Director

(SEAL)



**Cherokee County Cogen
PURPA Term Sheet for New 10-Year PPA
February 10, 2021**

Buyer:	Duke Energy Carolinas
Agreement:	Negotiated PURPA Agreement: Avoided cost rates calculated with updated inputs consistent with rates filed with PSCSC on Oct. 26, 2020 (2019-185-E) and PSCSC Order No. 2020-315A
Product:	Unit firm combined-cycle capacity and energy/tolling agreement
Term:	January 1, 2021 through December 31, 2030 (10 years)
Monthly Capacity Payment:	Contract Capacity x Monthly Capacity Charge x 1000
Contract Capacity:	[REDACTED] [REDACTED] [REDACTED]
Monthly Capacity Charge (\$/kW-month):	[REDACTED] [REDACTED]
Guaranteed Heat Rate:	[REDACTED] MMBtu/MWh
VOM:	[REDACTED]/MWh [REDACTED]
Start Charges:	[REDACTED]
Electric Delivery Point:	High side of GSU ("Into DEC")
Condition Precedent:	Written demonstration of QF status/eligibility; Binding negotiated PURPA agreement; Reg out/Full cost recovery
Performance:	Update existing contractual language to guarantee performance
Firmness/Scheduling:	Unit firm/Subject only to permit and operating limits
Credit Provisions:	Update existing contractual language to include current DEC security and performance assurance provisions

This negotiated pricing proposal presents Duke Energy Carolinas' avoided costs currently available to Cherokee under the Public Service Commission of South Carolina's implementation of PURPA. This proposal is not intended to be a binding offer or contract for the purchase and/or sale of electric energy or capacity. The terms and conditions set forth above are subject to negotiation, completion, and incorporation into a definitive agreement, which is executed by the parties respective managements. Mutually acceptable counterparty credit facilities must also be negotiated and executed. This negotiated pricing proposal shall remain available for 30 days from delivery by Duke Energy Carolina, subject to Duke Energy Carolinas agreeing to extend for an additional period not to exceed 30 days to complete ongoing negotiations.